DECLARATION OF JERRY PURVIS

I, Jerry Purvis, declare as follows:

1. My name is Jerry Purvis. I am the Vice President of Environmental Affairs at East Kentucky Power Cooperative ("East Kentucky"). I am over the age of 18 years, and I am competent to testify concerning the matters in this declaration. I have personal knowledge of the facts set forth in this declaration, and if called and sworn as a witness, could and would competently testify to them.

2. I have 30 years of experience in electricity generation. I have been employed at East Kentucky since 1994. I hold a bachelor's degree in Chemistry from Morehead State University and a bachelor's degree in Chemical Engineering from the University of Kentucky. I have a Masters of Business Administration from Morehead State University. As Vice President, I am responsible for promoting proactive environmental policies, implementing comprehensive compliance strategies, and supporting East Kentucky's sustainability goals. I manage East Kentucky's staff and outside consultants in pursuit of these goals.

3. East Kentucky is a member of the National Rural Electric Cooperative Association. This declaration is submitted in support of the legal challenges to EPA's final rule, "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," 89 Fed. Reg. 39798 (May 9, 2024) (the "Final Rule" or "Rule"). I am familiar with East Kentucky's operations, including generation and transmission, regulatory compliance, workforce management, and electric markets in general. I also am familiar with the Final Rule, and I am familiar with how the Final Rule will affect East Kentucky as well as its suppliers, members, customers, and employees.

4. East Kentucky is a not-for-profit that is owned, operated, and governed by its members, who use the energy and services East Kentucky provides. These owner-member cooperatives provide energy to 520,000 homes, farms, and businesses across 87 counties in Kentucky. East Kentucky's purpose is to generate electricity and transmit it to 16 Owner-

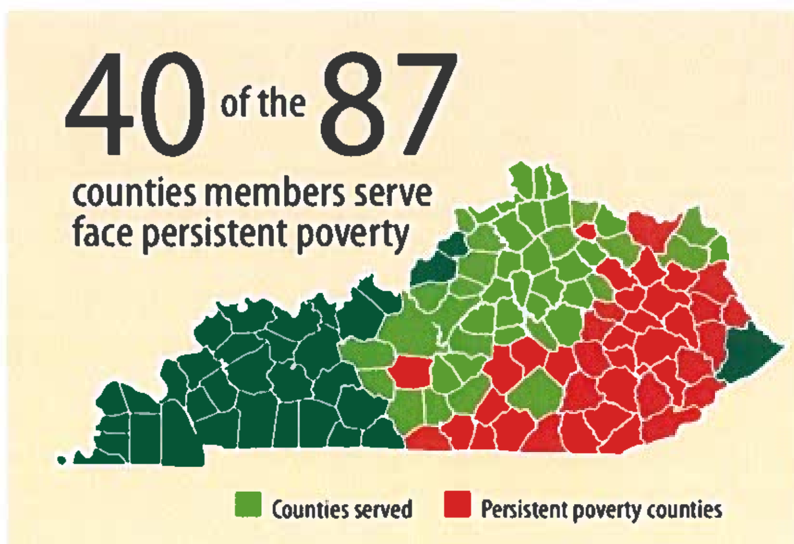
Member cooperatives that distribute it to retail, end-use consumers ("Owner-Members"). East Kentucky provides wholesale energy and services to Owner-Member distribution cooperatives through baseload units, peaking units, hydroelectric power, solar panels, landfill gas to energy units and distributed generation resource power purchases – transmitting power across the rural Kentucky areas via more than 2,900 miles of transmission lines. East Kentucky's Owner-Members' collective customer base is comprised largely of residential customers (93%). And, in 2019, 57% of East Kentucky's owner-member retail sales were to the residential class. Electricity is the primary method for water heating and home heating for this class of customers.

5. East Kentucky is a member of PJM Interconnection ("PJM"). PJM is a regional transmission organization ("RTO") that coordinates the movement of wholesale electricity in 13 states and the District of Columbia.

6. Demand for electricity is increasing in Kentucky. East Kentucky predicts increased demand during the time span in which this Final Rule would impact. East Kentucky forecasts net total energy requirements to

increase from 13.5 to 16.7 million MWh ("megawatt hours"), an average of 1.5 percent per year over the 2021 through 2035 period.[1] Residential sales will increase by 0.7 percent per year, and small commercial sales (customers with ≤1000 KVA ("kilo-volt-amperes")) will increase by 0.9 percent per year. The greatest area of growth will be for large commercial and industrial sales (customers with >1000 KVA), projected to increase by 3.3 percent per year.

7. East Kentucky is the voice for a substantial number of end users of electricity in its service territory that live in impoverished communities. These communities place a high value on affordable energy costs. East Kentucky's service territory includes rural areas with some of the lowest economic demographics in the United States. In these



[1] East Kentucky Integrated Resource Plan, Load forecast 2021-2035, December 2020 (IRP 2020).

areas, families are literally faced with a daily choice between food, electricity, and medicine. Of the 87 counties that East Kentucky's Owner-Member cooperatives serve, 40 counties experience persistent poverty, as reported by the USDA.

8. Many of these hardworking Americans have been plagued by unemployment from mines, trucking companies, restaurants and other businesses. The unemployment rate is 60% higher than the national average. They rely on government assistance to survive; anywhere from 30% to 54% of total income in most of the counties that East Kentucky serves comes from governmental assistance programs. Forty-two percent of these electricity users are elderly (65 years or older). Many are on fixed incomes and reside in energy-leaking mobile homes. Recent brutal cold weather has caused their monthly electric bills to skyrocket. East Kentucky has a strong interest in keeping energy affordable to assist its 16 Owner-Member cooperatives in serving people facing the harsh realities of today's economy.

EAST KENTUCKY'S ENVIRONMENTAL COMMITMENTS

9. East Kentucky and its Owner-Member cooperatives have a strong commitment to environmental excellence, which is underscored by a record of environmental over-compliance, investments in air control technology, waste water treatment, closure of ash ponds by removal, and managing waste dry and renewable diversification. East Kentucky has ensured that its efforts sustain excellent air quality, clean water, and properly disposed waste in accordance with and beyond regulatory minimums. East Kentucky is a leader in environmental stewardship in the Kentucky community. Kentucky Energy and Environmental Cabinet awarded East Kentucky its Beacon Award, the highest Environmental Stewardship award in Kentucky in 2023. In addition, East Kentucky has created a Strategic Sustainability Plan with goals and investments through 2035 and 2050. East Kentucky developed, permitted and built the first renewable energy sources in Kentucky. Since that time, East Kentucky launched a 60-acre photovoltaic solar array in Winchester, Kentucky, and East Kentucky continues to utilize landfill gas generation assets and to support hydroelectricity (Wolf Creek and Laurel Dams) via Southeastern

Power Administration ("SEPA") contracts. East Kentucky also just announced plans to construct an additional 136 MWs of solar capacity.

10. East Kentucky owns electric generating units ("affected EGUs") that fall within the Final Rule's scope of coverage and thus must comply with the Final Rule's stringent new standards for coal-fired steam units. These affected EGUs have remaining useful lives that will be significantly curtailed under the Final Rule—all at substantial cost to East Kentucky, and ultimately, to the rural ratepayers who are in East Kentucky's service area.

11. East Kentucky has one of the cleanest, best environmentally-controlled fleets in the country. East Kentucky's company-wide commitment to environmental excellence extends to compliance and a financial commitment to pollution control improvements at its generation facilities. East Kentucky and its 16 Owner-Member cooperatives **have invested over $1.8 billion** to reduce environmental impacts at its fossil generation facilities. Specifically, East Kentucky installed Best Available Control Technology ("BACT") level technology to control NOx, SO_2, and particulate matter (PM) emissions at its Spurlock and Cooper Plants. Those efforts extend to

significantly **lower SO_2 (95%), NOx (78%), PM (over 98%), and CO_2 (5.5%)** since 2005. Since 2008, East Kentucky has devoted substantial resources to ensure compliance with EPA final rules including the stringent Mercury and Air Toxics ("MATS") requirements. In fact, many of the units in its coal-fired fleet have qualified for low emitting EGU ("LEE") status. East Kentucky prides itself for installing state-of-the art emissions controls at its generation systems.

12. East Kentucky is an active participant in reducing its CO_2 footprint but recognizes that renewables must be balanced with coal-fired and dual-fueled natural gas-fired generation. East Kentucky installed 60 acres or 10 gross MWs of solar array commissioned in 2017 to begin to understand how renewables function within our system as a cleaner energy resource as our country transitions to cleaner resources. Yet, recent summer heat waves and winter freezes serve as stark evidence that renewable generation has operability and reliability constraints and is not always available to be dispatched when needed. Moreover, energy storage has not yet reached the point where it is able to completely fill the gaps in coverage

from renewable resources. Natural gas pipeline failures during Winter Storm Elliott also highlight the dangers of becoming too reliant on any single fuel source. Natural gas is delivered on a "just in time" basis, whereas coal is generally stockpiled so that many days or weeks of fuel is available to guard against unforeseen circumstances. Fossil-fuel generation plays an essential and undeniable role in grid reliability until technology advances.

OVERVIEW OF THE FINAL RULE

13. The Final Rule establishes CO_2 emissions limits that States must apply to existing coal-fired units, under Section 111(d). 89 Fed. Reg. at 39840. It also establishes limits for CO_2 emissions from new gas-fired combustion turbines, under Section 111(b). *Id.* at 39902. Under these limits, both existing coal-fired units and new gas-fired combustion turbine units must meet a stringent "presumptive standard of performance." *Id.* at 39836; *see id.* at 39823-24. That standard is the degree of emission reduction achievable by the application of 90% carbon capture and sequestration/storage ("CCS"). *See id.* 39801-02. Existing coal-fired units that do not deploy CCS must shut down (unless a State or federal regulator successfully invokes one of the

Rule's complex and discretionary exceptions). New units that do not reduce emissions to meet the presumptive standard must drastically reduce their output of electricity.

14. The Rule divides existing coal-fired units into three non-overlapping subsets: two "subcategories" and one "applicability exemption." *Id.* at 39841. These subsets are defined by whether a unit makes a federally enforceable commitment to retire, and by the date of that retirement. *See id.* To be effective, these commitments must be included in State plans, which are due to EPA in 24 months. *See id.* at 39874. If a unit does not commit to retire, it is placed into the first subcategory by default. *See id.* at 39841.

15. The first subcategory is for "long-term" units, which EPA defines as units that plan to operate on or after January 1, 2039. *Id.* at 39801. EPA says that the best system for these units is CCS that captures 90% of the CO_2 from a unit. *Id.* at 39845. The first part of this "system" is the design and installation of CCS technology. *Id.* at 39846. After that, the captured CO_2 must be transported (usually via pipeline) to a sequestration site that can

permanently store it (usually underground). *See id.* EPA "assumes" that "work" toward "each component of CCS" will begin in June 2024, *id.* at 39874, and the Rule requires that work to be completed before January 1, 2032, *id.* at 39801.

16. The second subcategory is for "medium term" units: those that make a federally enforceable commitment to "permanently cease operation before January 1, 2039." *Id.* EPA's best system for this subcategory is "co-firing with natural gas[] at a level of 40 percent "—*i.e.*, transforming a coal unit into one that combusts both coal *and* natural gas. *Id.* EPA assumes that medium-term units will begin compliance work in June 2024, and the Rule requires those units to reach full compliance by January 1, 2030. *Id.* at 39893.

17. Third, units that make a federally enforceable commitment to permanently cease operating by January 1, 2032 have an "applicability exemption" and are not subject to the Rule. *Id.* at 39801. But "[i]f a source continues to operate past this date, it is no longer exempt," and is thus in violation of the state plan and the Clean Air Act. *Id.* at 39843; *see id.* at 39991.

18. EPA deferred finalizing emissions guidelines for existing natural gas combustion turbines. The Final Rule does not address these units; rather, EPA has chosen to defer action to a separate, future rulemaking. Regardless, sources must immediately conduct resource-planning analyses to inform State plan elections. Without the benefit of a complete compliance landscape, these analyses will be challenging and create more uncertainty for the use of existing simple-cycle combustion turbines with regards to power supply planning.

19. For new and modified gas-fired combustion turbines, the Rule creates three subcategories, which are "based on electric sales (*i.e.*, utilization) relative to the combustion turbines' potential electric output to an electric distribution network." *Id.* at 39908.

20. "Low load" units are those that supply 20 percent or less of their potential electric output as net-electric sales. *Id.* at 39917. They must use lower-emitting fuels. *Id.* "Intermediate load" units are those that supply more than 20% but less than or equal to 40% of their potential electric output as net-electric sales. *Id.* These units must use highly efficient simple-cycle

turbine generation technology. *Id.* "Base load" units are those that supply greater than 40 percent of their potential electric output as net-electric sales. *Id.* These units must immediately comply with a multi-phase standard of performance. Phase I is based on highly efficient combined-cycle generation. *Id.* Phase II is based on 90% capture of CO_2 using CCS by January 1, 2032 (and is cumulative of Phase I). *Id.* Phase II requires units only to meet a stringent standard of performance, not to use any particular technology.

EAST KENTUCKY'S DISPATCHABLE COAL-FIRED ASSETS

21. Spurlock Station, East Kentucky's flagship plant, is located near Maysville, Kentucky on the Ohio River. All four units at Spurlock have state-of-the-art NOx, SO_2, PM, and Hg controls. In addition, East Kentucky has made substantial investments, to the tune of $262.4 million dollars, including a conversion to dry bottom ash, ash pond clean closure by removal, and new waste water treatment system with evaporation to ensure the plant is fully compliant with Effluent Limitation Guidelines ("ELGs") and the 2015 Coal Combustion Residuals ("CCR") rule. Spurlock is located adjacent to an International Paper corrugated packaging plant to which it is contractually-

committed to provide co-generation steam. The closest natural gas transmission pipeline is over 40 miles from Spurlock Station. The affected EGUs at the facility are:

- Unit 1 – is a wall-fired unit (344 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 1 has cold side ESP, WFGD, Wet ESP, SCR and low-NOx burners to control particulate matter (PM), SO2, SO3 / H2SO4 mist, and NOx respectively, installed on or before April 2009.
- Unit 2 – is a tangential-fired unit (555 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 2 has a hot side ESP, WFGD, Wet ESP, SCR, low-NOx burners, and over-fire air to control PM, SO2, SO3 / H2SO4 mist, and NOx, respectively, installed on or before 2008.
- Unit 3 – is a coal-fired circulating fluidized bed boiler ("CFB") unit (305 MW), which is designed to emit less NOx and SO_2 in the combustion process. Unit 3 has a SNCR to control NOx, a dry FGD to control SO2/SO3, and a filter fabric baghouse to control PM.

- Unit 4 – is a CFB unit (315 MW), which is designed to emit less NOx and SOx in the combustion process. Unit 4 has a SNCR to control NOx, a dry FGD to control SO2/SO3 and a filter fabric baghouse to control PM.

22. Cooper Station is located near Burnside, Kentucky adjacent to Lake Cumberland. Cooper Station is a critical generation asset due to its location in rural, south-central Kentucky that serves a transmission-constrained area. East Kentucky undertook significant control enhancements in 2013–2016, installing a pulse-jet fabric filter (baghouse) to control PM and dry FGD to control SO_2 in both units, and a SCR on Unit 2 to control NOx. The closest natural gas transmission pipeline is approximately 40 miles from Cooper Station. The affected EGUs at the facility are:

- Cooper Unit 1 – is a wall-fired unit (116 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 1 has low-NOx burners. It is tied into the Unit 2 dry FGD and pulse jet fabric filter to control SO_2 and PM and shares a common stack with Cooper Unit 2.

- Cooper Unit 2 – is a wall-fired unit (225 MW) pulverized coal-fired boiler that combusts bituminous coal. Unit 2 has a SCR and low-NOx burners, dry FGD and filter fabric baghouse to control PM and SO_2/SO_3. It shares a common stack with Cooper Unit 1.

23. The remaining depreciable life of Cooper Station and Spurlock Station extends past 2045 due to debt associated with the addition of environmental controls.

IMPACT OF THE FINAL RULE ON EAST KENTUCKY

24. East Kentucky relies on affected EGUs for more than 50% capacity of its current generation needs. Accordingly, the Final Rule will have a substantial impact on every aspect of East Kentucky's operations. These impacts will ultimately fall most heavily on rural Kentucky ratepayers.

I. Impacts of Carbon Capture and Storage as BSER

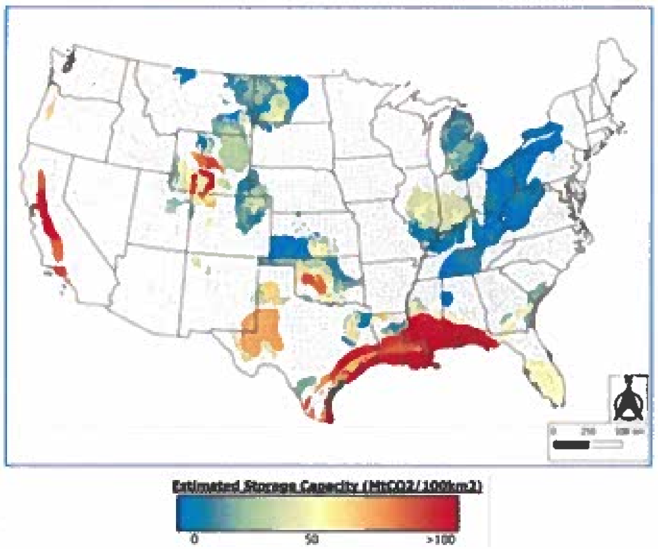
25. CCS is impracticable and infeasible at Spurlock or Cooper. The Final Rule allows affected EGUs to remain in operation beyond 2038 only if

they can achieve 90% capture of carbon using CCS by 2032. But this is impossible at Spurlock and Cooper for the following reasons.

26. The technology to reliably achieve 90% capture of CO_2 using CCS is not commercially demonstrated or readily available. Even the emerging technology that is available is unreliable, not technology ready at the levels necessary to comply with the Final Rule and prohibitively expensive. CCS is potentially feasible, but it has not been adequately demonstrated. To be adequately demonstrated, CCS must be possible at all sites with existing coal-fired units, at all boiler-types, and at all loads. CCS has not been proven, even as a pre-demonstration project, at the size needed to treat the flue gas of a large coal-fired EGU such as those in the East Kentucky fleet. Technological issues are not the only thing preventing Spurlock and Cooper from relying on the CCS compliance pathway.

27. Even if 90% of the CO_2 could be captured, it would need to be transported for storage. For East Kentucky's plants, no CO_2 sequestration site or injection wells reside nearby. The Kentucky Society of Geologists and the University of Kentucky conducted testing at Hancock County, Kentucky

in 2009-2012 to sequester 1,500 tons of carbon dioxide.[2] After tests of sequestering 323 tons, officials reported that it would take 350 acres or more of land per well, which presented an "obstacle," and that "parasitic load of 25-30 percent" would occur. Future projects need to be at or below 10 percent parasitic load to be viable. The geology in Kentucky does not support storage of carbon at utility-grade levels with the



required acreage, the lack of Kentucky regulations to mitigate risk to the sequestering company, and high degrees of parasitic load. In fact, Cooper Station is located in an area of karst terrain. The Electric Power Research Institute ("EPRI") conducted a study of locations in the United States suitable for carbon storage. Kentucky is generally identified in blue as an area with limited carbon storage potential. This means that an unworkable

[2] Topical Report: Summary of Carbon Storage Project Public Information Meeting and Open House, Hawesville, Kentucky, October 28, 2010, Report No. DOE/FE0002068 (June 25, 2012) ("DOE Carbon Storage Report").

amount of space would be needed to store enough CO_2 from a utility unit, not to mention CO_2 storage from an entire fleet.

28. To purchase the underground pore space to secure sufficient storage space is likely impossible – no such market actively exists – but certainly would cost more than East Kentucky's balance sheet.

29. No pipeline exists to carry captured CO_2 from Spurlock or Cooper to a storage location. The nearest areas with favorable geology in which CO_2 can be stored, according to EPRI,[3] would be in Illinois at a distance of 350 miles from Spurlock. Any such pipeline would need to cross miles of terrain at significant expense, or ***$10.7 million per mile of pipeline.***[4] ***To lay 350 miles of line would total over $3.7 billion*** – which is roughly equivalent East Kentucky's entire net book value today.

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[3] EPRI, Geospatial Modeling of Geologic Carbon Dioxide Storage Potential (June 30, 2023).

[4] Smith, "Land pipeline construction costs hit record $10.7 million/mile Oil and Gas Journal (Oct. 2, 2023), https://www.ogj.com/pipelines-transportation/pipelines/article/14299952/land-pipeline-construction-costs-hit-record-107-million-mile

30. Setting aside the self-evidently prohibitive costs that such a pipeline would entail, the evaluation, permitting, siting, design, and construction would all take much longer than the 7 years between now and the compliance date required by the Final Rule.[5] The pipeline could not, and would not, be operational before 2032.

31. Safety considerations should not be brushed aside. Although pipelines are regulated by the Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA,") oversight of pipelines cannot completely ameliorate the inherent risks from failures, as was illustrated by the CO_2 pipeline failure in Satartia, Mississippi. Accordingly, CCS is not an option for Spurlock and Cooper because there exists no readily available infrastructure to store or transport the captured CO_2.

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[5] Gas pipelines have experienced substantial delays due to legal and compliance issues. World Pipelines, "Court rulings, delays and cancellations underscore challenges for gas pipeline construction" (July 15, 2021). CO2 pipelines are expected to encounter similar delays.

32. CCS Projects are prohibitively expensive due to development, one-time capital costs, and ongoing operating costs. Project Tundra, a large-scale CCS project in Center, North Dakota, is estimated at a cost of over $1.6 billion to construct. It is designed to treat 530 MW of flue gas, which is the largest scale project of its kind in North America. The scale of Project Tundra – which involves injection into an adjacent underground storage facility – would not be large enough to cover the flue gas from Spurlock Unit 2 (555 MW) and certainly not the 1,519 MW gross that the Spurlock units collectively generate.

33. Using Project Tundra as a model, for each of the Spurlock units, East Kentucky calculated the capital cost of installing CCS, the carrying cost of the loan required for the project, and the ongoing operation costs of CCS.

34. The following Table A illustrates these costs based on publicly-available information for Project Tundra. The CCS capital project on its own would cost $6.2 billion dollars for all four Spurlock units, which would need to be financed. Finally, estimated operational costs of CCS equipment would total $17.74 per megawatt hour annually. The cost of storing the captured

CO_2 adds another $2.2 billion, which would have to be transported to Illinois as the closest feasible storage location at a cost of over $3.7 billion. The grand total is $10.7 billion, collectively. Even this analysis does not fully take into account the cost of the parasitic nature of CCS load. To keep existing EGUs in operation, the Final Rule will create an absurd and unintended consequence of stimulating the construction of generation assets to replace the megawatts lost to operate CCS systems.[6]

Table A – CCS Capital Investment and Operational Costs, Separately

Capital Investment				45Q Tax Credit	Cost per MWH		
Capital Cost CCUS	Capital Cost Transportation	Capital Cost Storage	Capital Investment Total	45Q Tax Credit ($/ton)	45Q Credit	Total	Total 45Q
$1,352,093,023	$816,497,093	$165,599,834	$2,334,189,950	$ 77.11	$75.52	$202.85	$127.33
$2,433,767,442	$1,469,694,767	$298,079,701	$4,201,541,910	$ 77.11	$75.45	$202.83	$127.38
$1,207,869,767	$729,404,070	$147,935,851	$2,085,209,689	$ 77.11	$68.31	$201.10	$132.79
$1,207,869,767	$729,404,070	$147,935,851	$2,085,209,689	$ 77.11	$71.43	$201.86	$130.43
$6,201,600,000	$3,745,000,000	$759,551,237	$10,706,151,237	$ 77.11	$73.29	**$202.31**	**$129.02**

35. Table A provides the capital investment total, which is the cost to construct the CCS project ($10,706,151,237.00) in the orange shaded area.

[6] DOE Carbon Storage Report (reflecting 25-30% losses to operate the CCS system).

The green area identifies the IRC 45Q tax credit that CCS facilities may receive in dollars per ton ($77.11/ton). Finally, in the tan area, East Kentucky calculates the cost per megawatt hour to include the operational costs of running the CCS system on an annual basis ($202.31), which reduces to $129.02 per megawatt hour after applying $73.29 of benefits from 45Q tax credits. The 45Q tax credits marginally reduce the annual costs, but the credits hardly place a dent in the overwhelming expense of operating CCS. Table A's cost per megawatt hour ($129.02) *does not include* the costs to build the project ($10,706,151,237.00). Table B, below, cumulates these costs.

Table B – CCS Annual Capital Investment and Operational Costs, Cumulative Total including 45Q Benefits

Annual Costs for Spurlock Station CCS		5/8/2024
Spurlock CCS Operational Costs w/45Q	Cost CO2 (45Q)	Operational Annual
MWh	$/MWh	$/year
10,245,696	129.0168251	$ 1,321,867,168.52
Spurlock CCS + Storage Capital Total Cost	Finance	Capital Annual
$	Carrying cost	$/year
$ 10,706,151,237.07	0.177	$ 1,891,063,180.17
<u>Total Cost Summary</u> Spurlock Station, $/MWh	MWh	Total cost/MWh

Annual Payment (CCS, Transportation and Storage) accounting for all 45Q tax credit benefits		
$3,212,930,348.69*	10,245,696	$ 313.59

*This value is based on the sum of capital costs to construct CCS added to operational costs. These values are based on the generation forecast.

36. Table B provides an annual payment per year based on generation forecast taking into consideration capital (construction) costs and operational costs over 12 years and applying the benefits of 45Q tax credits. A carrying cost is also applied for financing.

37. East Kentucky included the impacts of the 45Q tax credit for carbon capture on the cost of the project to the cooperative and its ratepayers. East Kentucky calculated the value of the 45Q credit at $73.29 per MWh or $77.11/ton. When applying that value to reduce the cost of CCS, the net remaining cost per megawatt hour is $129.02. When applied to Spurlock's estimated hours per megawatt, the annual cost of CCS is $3.2 billion dollars, $1.321 billion in the cost of operating a carbon capture system, including 45Q and capital annual payment of $1.891 billion annually or an increase to normal costs of $313.59/MWh, an alarming increase in rates to rural Kentuckians.

38. East Kentucky calculated the estimated cost of the project, including 45Q tax credits, on its ratepayers. The 45Q benefits do not practically take effect until approximately 2 years after the project begins operation. Consequently, East Kentucky must shoulder $10.7 billion in costs during project development and in the early years of CCS operation. A project of this magnitude would be impossible for East Kentucky to finance —even without long-term expenditures, such as carrying costs—because just the initial capital outlay far exceeds the cooperative's entire balance sheet and ability to support this financing activity. After investing billions of dollars for CCS, East Kentucky will produce fewer megawatts of electrical generation than it produces now due to parasitic load.

39. The 45Q credit reduces the cost of CCS to ratepayers, but that benefit does not practically take effect until approximately 2 years after the project begins operation. Therefore, it is crucial to evaluate the costs to ratepayers prior to benefits begin flowing from 45Q and then after those benefits take effect. Importantly, 45Q tax credits expire in 12 years, limiting their long-term benefits to East Kentucky's ratepayers.

40. East Kentucky calculated the rate impact, including 45Q, to a residential customer at the end of the line. On a monthly basis, an average residential bill would cost $157, but with CCS, the bill increases to $263 - 308, based on the number of kWh required to power an average Kentucky residence. This is a 67 – 96% increase to residential bills, solely based on adding CCS to Spurlock. Such an increase is staggering and not possible, nor likely to be approved by the Kentucky PSC.

Table C – East Kentucky Rate Projections – CCS Impacts

East Kentucky Rate Analysis	12 years	30 years
Incremental Residential Rate (per kWh)	$0.12483	$0.08709
Average usage (kWh)	1210	1210
Incremental Average Increase	$151	$105
Average Residential Bill	$157	$157
Bill plus GHG Increment	$308	$263
% Increase over current rate	96%	67%

41. The costs presented are for Spurlock only. They do not include the cost to treat the flue gas at Cooper, which would require a separate system entirely, for the two units at that facility.

42. The costs of CCS would ultimately be passed to the customers at the end of the line, the vast majority of whom would be very unlikely to be

able to afford the rate increase. To put that cost in perspective, an average Kentucky household would receive electricity bills that are double the amount billed with 45Q prior to the Final Rule, even accounting for the benefits of 45Q. This estimate would escalate in the winter when heating requirements are highest. East Kentucky's customers that live in poorly insulated modular homes most often use electricity for heat. During winter days with temperatures well below freezing, these residents will use even more kilowatts to survive these events. The CCS price-doubling effect during peak electricity usage in extreme weather events cannot be sustained by rural end-users, particularly those in economically disadvantaged communities. The Final Rule therefore works at cross-purposes to one of the express cornerstones of the Biden Administration's energy policies, which is environmental justice. The economic impact of the Final Rule will be most harshly felt by those consumers who are already challenged to afford energy costs, where any consumers in energy inefficient housing would see energy costs exceed housing and/or food costs on a monthly basis.

43. In summary, to treat all of the flue gas at Spurlock using CCS on a continuing basis, the price tag would be $10.7 billion, including the capital cost, storage cost, transportation cost, project carrying cost, and operation & maintenance cost. This price tag is unquestionably excessive, and CCS as a compliance strategy is unsustainable and dangerously naive.

II. Impacts of Natural Gas Co-firing as a BSER Alternative

44. As an alternative to CCS, the Final Rule allows affected EGUs to remain in operation until January 1, 2039 if they begin co-firing with 40% natural gas by 2030. Natural gas co-firing may not be achievable at all of East Kentucky's coal-fired units. East Kentucky's bituminous units (Spurlock Unit 1 and Unit 2 and Cooper Unit 1 and Unit 2) can be retrofitted to co-fire with natural gas, but the project is exceedingly expensive, as explained *infra*. East Kentucky is presently evaluating whether co-firing is feasible for Spurlock Units 3 and 4. These units utilize Circulating Fluidized Bed ("CFB") technology, which is designed to lower emissions utilizing a fluidized bed in the boiler. Spurlock Units 3 and 4 were not designed to co-fire natural gas. The Final Rule does not take into account the various technologies for

deriving fuel from coal-fired generation units. A "one size fits all" approach is unreasonable and unworkable.

45. For the other East Kentucky coal-fired units, the ability to co-fire theoretically exists, but requires new infrastructure that does not exist. The closest natural gas transmission pipeline is over 40 miles away. East Kentucky estimates that the cost of the required pipeline would be approximately $500 Million, which exceeds the value of $400 to $450 million per line that East Kentucky provided in comments for the Rule.

46. Given the long lead times for construction projects, a pipeline operator must begin design, permitting, siting, procurement, and construction immediately to have natural gas available in time for the Final Rule's 2030 deadline. But no operator is likely to take all those steps without a substantial, up-front commitment from East Kentucky—in the form of a long-term (20–30 year) supply contract. Even if East Kentucky identified an operator and agreed to such terms, there is no guarantee that such a pipeline would actually be completed on a timely basis. Permitting, construction delays, right-of-way issues, and myriad other factors could block the

pipeline or could delay it beyond the Final Rule's deadlines, which are discussed in more detail *infra*. This places utilities such as East Kentucky in a completely untenable position where their ability to comply with the Final Rule is reliant upon the actions of pipeline developers to construct and operate new pipelines in near record time.

III. Impacts of BSER Alternative Retirement Options

47. The remaining option would shut down 1,519 MW gross of East Kentucky's coal generation by 2032. This alternative would require East Kentucky to build replacement generation assets or purchase power from the market – assuming it is available – to meet its electricity demands. This option creates substantial reliability concerns. At a time when Kentucky has already experienced rolling blackouts due some utilities' ability to serve load during peak winter conditions based upon the *existing* resource portfolio, forcing the arbitrary, premature closure of thousands of megawatts of existing baseload capacity will place even greater strain on the ability of grid operators to keep power flowing and meet demand.

48. *Replacement Power.* Congress authorized funding through the Inflation Reduction Act to build solar arrays and other renewable resources for cooperatives. East Kentucky is actively engaging to do so with the assistance of the United States Department of Agriculture Rural Utilities Service. However, renewable generation is intermittent, running appropriately 25% of the time as compared to the higher, dispatchable capacity factors of retiring coal units or natural gas-fired units. East Kentucky looks forward to the opportunity to add more renewable resources, including filing for regulatory approval of two brand new solar facilities last month, but those resources are not a substitute for dispatchable energy generation.

49. East Kentucky is highly concerned with the timelines to replace generating assets given regulatory requirements, timelines, and costs to replace 1,883 MW gross of coal-fired generation. The Final Rule prematurely retires existing generating assets while East Kentucky is facing increased demand for electricity in East Kentucky's service area. East Kentucky is concerned by potential delays subject to market conditions due to:

a. *Supply chain delays and costs.* Original equipment manufacturers will soon be inundated with new purchase orders from EGUs across the country. For example, the lead time for the step-up transformer necessary to connect new gas units to the grid is already 36 months. That number will only grow if the Final Rule takes effect. This creates a "race" among EGUs that need to order new equipment, each one hoping to be nearer the front of the queue. East Kentucky is not immune to that dynamic. Thus, East Kentucky has no choice but to soon begin purchasing equipment before the courts can adjudicate NRECA's challenge to the Final Rule on the merits. Electric Generating Utilities will be in the market at the same time, resulting in an imbalance between supply and demand, which arbitrarily escalates prices for virtually everything.

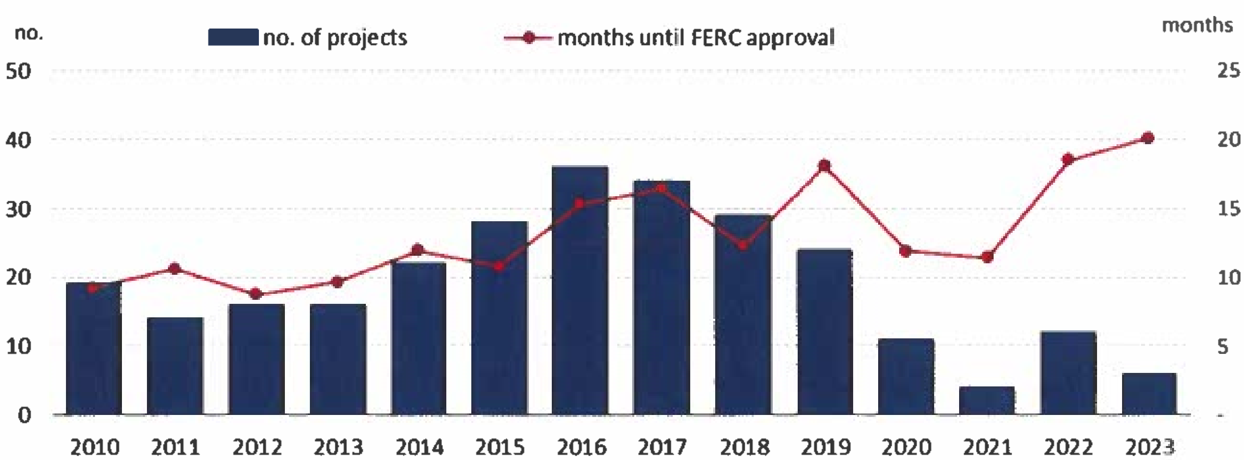
b. *Labor market delays.* Complying with the Final Rule will require East Kentucky to hire a large number of consultants, engineers, attorneys, and other professionals to manage the vast amounts of design, modeling, permitting, and other work required under the Final Rule. Yet these markets are also subject to the laws of supply and demand. As utilities across the nation rush to hire the same professionals, prices will increase. Accordingly, utilities must move early—not only to insulate themselves from price pressures, but also in an attempt to ensure that the needed professionals are even available on a timely basis.

c. *Gas Pipeline Construction Delays*. Recent projects to build natural gas pipelines have been substantially behind. Numerous challenges contributed to projects extending far beyond their planned schedules.[7] Specifically, eminent domain challenges and FERC approvals have slowed construction. The FERC approval timeline for new pipeline projects has consistently

[7] FERC certificate applications are often subject to public scrutiny for gas pipelines, resulting in significant delays and potential protracted litigation. Congressional Research Service, "Interstate Natural Gas Pipeline Siting: FERC Policy and Issues for Congress" (June 9, 2022). For example, increased public scrutiny and opposition to any new pipeline project in the country (e.g., Mountain Valley, Keystone XL, Dakota Access) has led to a significant increase in approval time for new pipeline projects.

increased since 2010 (excluding 2020 and 2021, which were impacted by the COVID-19 pandemic). In comparison, the average project approved in 2023 spent over 20 months in the FERC approval process. Aside from the increased length of the FERC approval process, FERC actually approved fewer projects each year since its peak in 2016. In 2022, the commission only approved 12 pipeline projects. The following Table D, using FERC data, illustrates these real-time delays and the diminishing numbers of project approvals.

Table D – FERC Approval Length of Time



Source: FERC natural gas pipeline approval database

d. *Activation and Deactivation RTO Interconnection Delays.* Deactivation requires notice and coordination with the RTO. PJM requires as little as 90 days of advance notice prior to the proposed deactivation date, at which time PJM conducts a reliability analysis.[8] This analysis determines whether any transmission grid reinforcement is necessary to ensure the reliable flow of power to load centers in PJM. Significant network upgrades (costs) are likely necessary to reinforce the transmission system due to the lack of generation. The Final Rule will generate a substantial number of coal-fired unit deactivation requests within the same time period (2028-2032). Analysis of each of these requests individually and collectively would be quite complex, particularly given that, collectively, large-capacity deactivations are anticipated to occur within a narrow,

[8] PJM Open Access Transmission Tariff (OATT), Part V, Section 113.1. PJM batches all deactivation requests on a quarterly basis and then has 60 days following the end of the quarter to perform the reliability analysis.

overlapping, not-too-distant time frame, which will have significant grid implications. An activation proposal to add generation must be studied to determine whether any transmission grid reinforcements must be constructed prior to the generator injecting power into the grid. Studies ensure that the electricity produced can be delivered to load in the region. The magnitude of interconnection requests and the inefficiencies inherent in the interconnection processes severely delay the timeline for bringing a new resource on-line. Many Regional Transmission Organizations, including PJM, have 25% or more requests backlogged in the process. PJM has reformed the process and is working through the backlog of projects. However, the most optimistic scenario for any new project entering the queue today is that PJM would likely require until 2028 to complete the necessary analysis to finally determine what is required to allow the unit to reliably connect to the system by the future anticipated in service date. Signing a

Generator Interconnection Agreement in 2028, for example, does not mean that the new generator will begin to inject power in 2028. Moreover, successful completion of the study process does not necessarily ensure that the resources connect and contribute to the reliability of the system. A concerning trend has been observed. According to Lawrence Berkeley National Laboratories, more than 300,000 MW of projects have been approved nationally but have not proceeded to construction – nearly 25% of current generating capacity in the country. Right now, PJM has cleared nearly 40,000 MW of generation projects through the interconnection process that are not moving to construction. Nothing from PJM is holding these projects back, yet they sit idle in PJM and elsewhere due to continued challenges with supply chain, financing and local siting issues.

e. *Purchasing Power Unhedged Off the Market*. East Kentucky would place itself in great economic peril if it did not pursue replacement "steel on the ground." The Kentucky Public Service

Commission "does not expect to allow a utility to depend on market-purchases for its long-term capacity needs . . . . it follows that market capacity is not the cost the utility is avoiding. Rather, the likelihood is that the utility will replace generation capacity with "steel in the ground" or a Purchase Power Agreement. Order, Case No. 2021-00198 (Ky. P.S.C. Oct 26, 2021).[9] By forcing generation shifts based upon arbitrary standards that are impossible to satisfy, the Final Rule has the effect of usurping state authority over resource planning and ratemaking.

f. *State regulatory delays*. Kentucky Senate Bill 4, enacted as 2023 Kentucky Acts Chapter 118, provides that a utility cannot retire an electric generating unit without the approval of the Kentucky Public Service Commission. The Commission's decision is discretionary based on its review of factors set out in the statute. Thus, there is no guarantee that the Commission would allow

[9] East Kentucky Annual PURPA QF Tariff Filing, Case No. 2021-00198 (Oct. 26, 2021), https://tinyurl.com/mwtvwka4

East Kentucky to retire any EGUs that cannot be brought into compliance with the Final Rule. This could put East Kentucky in the uneasy position of not being able to comply with the Final Rule and simultaneously not being able to avoid violating the Rule by retiring EGUs that cannot be brought into compliance.

IV. Overall Impacts of EPA's BSER Approach

50. No matter what subcategory it chooses for Spurlock and Cooper, East Kentucky must immediately begin spending extraordinary sums of money across several expense categories (and indeed already *has* begun planning these expenses in preparation for having to comply with the Final Rule), and these expenditures might not be enough to maintain grid reliability.

51. These expenditures are shouldered by East Kentucky's member cooperatives and, ultimately, by end users in rural communities – many of which are in communities of poverty.

52. If the Final Rule takes effect, electric markets will be highly constrained, as generators across the country will see reductions in their portfolios.

53. Depending wholly on the market for 1,883 MW gross of baseload power at a time when the entire market is being forced to prematurely retire baseload EGUs that are the backbone of the bulk power grid is not possible or realistic given the economic exposure and regulatory requirements in Kentucky that require East Kentucky to replace generation capacity with "steel on the ground."

54. Accordingly, East Kentucky must construct new generation to replace any capacity coming off the grid as a result of the Final Rule and the increased demand for electricity in Kentucky. Yet the Final Rule also imposes stringent requirements that apply to new EGUs, which must achieve 90% capture of carbon using CCS for base load generation. CCS is not possible for a new natural gas EGU without a feasible and cost-effective means to transport and storage the captured CO_2 – even if a 90% capture rate can be achieved for a gas unit. Nor can East Kentucky depend on intermittent

renewables for baseload generation. The Final Rule has the effect of frustrating East Kentucky's ability to provide reliable and affordable power.

55. The Final Rule's requirements relegate gas-fired units to the intermediate or low-load categories if CCS is not installed. CCS has not been adequately demonstrated or commercially available for natural gas combined cycle operations. The new generation options in the Final Rule have an immediate detrimental impact on East Kentucky's ability to construct replacement generation.

56. Since CCS is not an option for East Kentucky, the cooperative is faced with two unworkable alternatives:

a. If East Kentucky constructs a natural gas combined cycle unit, that new unit could be limited to a 40% capacity factor based on the intermediate load category's CO_2 emissions requirements. A natural gas combined cycle is a large capital investment at $1,576 per kilowatt hour, yet East Kentucky would have to build two natural gas combined cycle units to reach the same generation capacity that one unit is capable of achieving. This outcome is absurd on its face. In other words, the project price tag would arbitrarily be doubled simply by bureaucratic fiat in order to achieve the same net generation output.

b. If East Kentucky constructed a natural gas simple cycle turbine, that new unit could be limited to a 20% capacity factor based on the low load category's CO_2 emissions requirements. A natural gas simple cycle turbine is also a significant expenditure and investment.

57. In summary, the Final Rule's requirements are detrimental to East Kentucky, its members, and end users. By requiring CCS, the requirements substantially restrict East Kentucky from adding new generation or continuing to operate its existing assets for their full useful life as originally envisioned by regulators. Reliability is at stake due to the dual threat that the Final Rule imposes on existing and new generation projects.

ABSENT A STAY, EAST KENTUCKY WILL SUFFER IMMEDIATE IRREPARABLE HARM

58. During the pendency of this litigation, East Kentucky would sustain the following concrete harms if a stay of the Final Rule is not granted:

a. The costs to immediately begin a project to construct replacement power assets to replace prematurely retiring coal assets at Cooper and Spurlock (costs which will be inflated due to economic conditions forced by industry-wide upheavals resulting from the Final Rule and the inability of venders and providers to meet unprecedented demand):

i. Project development costs, including land acquisition, permitting, studies, engineering, and regulatory compliance costs.

ii. Equipment costs of the new generation asset. Based on EIA data, the calculated cost of a new unit to replace the megawatts generated at Spurlock and Cooper is:

EIA Electric Power Data
Guide: EIA 860
$/kW 1576

		MWg	kW	NGCC	total, $ M
Spurlock Station		1519	1519000	1576	2,393
Cooper Station		364	364000	1576	574

* Does not include any technology integration dollars to plant site or grid
** capital costs multiplied by station capacity

b. The cost to immediately begin constructing a gas line for either a new gas unit at Spurlock and Cooper or the ability to co-fire gas at its non-CFB units.

c. The cost to launch a project to retrofit Spurlock 1 and 2 and Cooper 1 and 2 to provide for co-firing with natural gas.

d. The cost to retrofit the coal-fired units with CCS. At the highest price, this option would not likely be pursued, even aside from substantial feasibility concerns raised above. It is the harm that would be incurred if East Kentucky complied with BSER for existing coal-fired units.

59. Equipment cannot be returned. Dollars spent on design, permitting, engineering, and other studies cannot be refunded. Legally binding retirement promises cannot be undone. The costs of these projects are more than several multiples of East Kentucky's entire balance sheet.

60. The Final Rule imposes substantial financial harm to East Kentucky by stranding existing debt on its coal-fired assets. East Kentucky

would still hold $774.811 million in debt for the units at Spurlock on the compliance date to shutdown coal in the Final Rule (December 31, 2031).

61. Demand for electricity in Kentucky is steadily increasing. East Kentucky is looking to commence construction to obtain new and replacement generation during the pendency of this litigation. East Kentucky is harmed by the Final Rule's restrictions on new generation, which would require East Kentucky to commit to double its project scope (*e.g.*, two combined cycle units instead of one) to achieve the same number of megawatts to meet demand. Gas generation projects can only realize 40% or less of the heat input capabilities of the units without CCS technology.

62. If East Kentucky must purchase power from the market, that market price varies based on many market factors. PJM real time market costs ranged from $4,199 (December 23, 2022) to $9.07 (August 20, 2023) per MW/hr looking at data from 2022 through 2023. PJM market prices in 2022 averaged $80.14 MW/hr., which was an 101% increase over the 2021 average megawatt per hour price. Market exposure could harm East Kentucky to the extent that its entire financial security would be in jeopardy.

63. Market pricing during a grid failure could result in extreme power prices that quickly lead to the bankruptcy of a generation and transmission cooperative, which is what happened to Brazos Electric Power Cooperative during the Texas 2021 ice storm.

64. The Table E below illustrates the cost to replace generation from East Kentucky's existing coal generating plants on December 23, 2022 and December 24, 2022 when Winter Storm Elliot hit. Market clearing prices skyrocket when the market is short of energy reserves, exposing unhedged load-serving entities. If Spurlock and Cooper were unable to operate, the total cost would have been ***over $74.5 million for just two days of extreme cold***. These costs would be passed along to East Kentucky's ratepayers. Some of the nation's poorest communities, which are located in East Kentucky's service territory, cannot and should not have to bear this tremendous risk and burden.

Table E – Cost to Purchase Generation on the Market

East Kentucky Coal-Fired Generating Stations	**December 23, 2022**	**December 24, 2022**
Spurlock Station	$25M	$34M
Cooper Station	$6.5M	$9M

Total Power Purchase Cost	$31.5M	$43M

65. A summary of East Kentucky's financial harms is provided in Table F below:

Table F -- Summary of Costs of the Final Rule to East Kentucky

East Kentucky's Financial Harms	Cost	Source of cost
Cost of Constructing Replacement Generation	$1,579.64 /kW	EIA Form 860
Cost of Constructing a gas line to Spurlock	>$500 million	Estimates
Cost of Constructing a gas line to Cooper	>$500 million	Estimates
Cost of stranding debt on the Rule's compliance date	$774.811 million	Financial records
Exposure of Purchasing replacement MWs in the PJM market	Variable. Exposure can be extreme as depicted by the cost of $74.5 million (dollars per megawatt hour) for two days of replacement electricity in December 2022	PJM Market Costs; see Table E
Cost of CCS as applied to Spurlock, including capital, transportation, storage and carrying costs	$10.7 billion capital, annual payment estimate, $1,891,063,180.17/year, $129 per MWh CO2 w/ 45Q, estimated cost $1,321,867,168.52 / year	Based on calculations using Project Tundra as a pricing example; see Tables A and B

66. If replacement power is not available for purchase or constructed in time, reliability is at stake. A grid failure would cause damage to East Kentucky, its members, the economy, and the public health of end users in its service territory. Kentuckians rely on electricity to heat and cool their homes. Affordable and consistent power allows for medical providers to provide essential services to the elderly, infirm, and to vulnerable individuals with chronic health conditions. Evidence from grid failures in other areas of the country in winter storms Uri and Elliott shows the documented health impacts and morbidity caused by those events. Other concrete damages would occur such as business shutdowns, food spoilage, property damage, and lost labor productivity. Further economic development in Kentucky is at risk without the ability to provide sufficient energy to support new factories, data centers, and other infrastructure necessary to attract industry, and, in turn, create new jobs. Energy powers the economy from which the government derives tax revenues. Reliability consequences are at stake prior to the resolution of this litigation due to the increased demand for power in Kentucky and the premature retirements

and limitations on the construction of new generation imposed by this Final Rule.

67. All of these near-term costs will begin flowing immediately to East Kentucky's members—and ultimately to the rural ratepayers who depend on it for reliable service.

68. Moreover, these costs cannot be deferred or delayed until the courts reach a final determination on the merits of NRECA's Petition for Review. East Kentucky expects that process to take *at least* 3-5 years (indeed, litigating the Clean Power Plan took 7 years). But the Final Rule's compliance deadlines do not give East Kentucky any time to spare.

69. If the Rule remains in effect while NRECA's challenge to the Rule is pending, East Kentucky will have no choice but to incur significant non-refundable compliance costs as well as to shoulder the many other substantial, immediate, and irreparable harms described above. And the consumers who rely on power generated by East Kentucky might find themselves with less reliable power or without the means to pay for it, or both.

* * *

I declare under penalty of perjury under the laws of the United States of America, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 9th day of May, 2024, in Winchester, Kentucky.

Jerry B. Purvis

Jerry B. Purvis, Vice President of
Environmental Affairs